TESTIMONY OF
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ON BEHALF OF THE
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITEE ON HIGHWAYS, TRANSIT AND PIPELINES
COMMITTEE ON TRANSPORTATION AND INFRASTRUCTURE
U.S. HOUSE OF REPRESENTATIVES

REGARDING THE
REAUTHORIZATION OF THE PIPELINE SAFETY ACT

MARCH 16TH, 2006

Mr. Chairman and Members of the Subcommittee:

Good morning. My name is Jeryl Mohn, and I am Senior Vice President of Operations and Engineering for Panhandle Energy. I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovencial natural gas pipeline industry in North America. INGAA's members transport over 90 percent of the natural gas consumed in the United States, through a network of approximately 200,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system – in other words, large capacity systems spanning multiple states or regions.

Panhandle Energy, headquartered in Houston, Texas, is a subsidiary of the Southern Union Company, and owns or holds a major ownership interest in five interstate pipelines and a liquefied natural gas import terminal. Our pipelines serve a significant share of the markets in the Midwest, the Southwest including California, and Florida. In addition, our Trunkline LNG terminal in Lake Charles, Louisiana is one of the nation's largest LNG import facilities.

INDUSTRY BACKGROUND

Mr. Chairman, natural gas provides 25 percent of the energy consumed in the U.S. annually, second only to petroleum and exceeding that of coal or nuclear. From home heating and cooking, to industrial processes, to power generation, natural gas is a versatile and strategically important energy resource.

INGAA's members transport over 90 percent of the natural gas consumed in the United States, through a network of approximately 200,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system – in other words, large capacity systems spanning multiple states or regions.

As a result of the regulatory restructuring of the industry during the 1980s and early 1990s, interstate natural gas pipelines no longer buy or sell natural gas. Interstate pipelines do not take title to the natural gas moving through our pipelines. Instead, pipeline companies sell transportation capacity in much the same way as a railroad, airline or trucking company.

Because the natural gas pipeline network is essentially a "just-in-time" delivery system, with limited storage capacity, customers large and small depend on reliable around-the-clock service. That is an important reason why the safe and reliable operation of our pipeline systems is so important. The natural gas transmission pipelines operated by INGAA's members and by others historically have been the safest mode of transportation in the United States. And the interstate pipeline industry, working cooperatively with the Pipeline and Hazardous Materials Safety Administration (PHMSA), is taking affirmative steps to make this valuable infrastructure even safer.

Congressional involvement in pipeline safety dates back almost 40 years to enactment of the Natural Gas Pipeline Safety Act in 1968. This legislation borrowed heavily from the engineering standards that had been developed over the previous decades. The goals of this federal legislation were to ensure the consistent use of best practices for pipeline safety practices across the entire industry, to encourage continual improvement in safety procedures and to verify compliance. While subsequent reauthorization bills have improved upon the original, the core objectives of the federal pipeline safety law have remained a constant.

HOW SAFE ARE NATURAL GAS PIPELINES

While the safety record of natural gas transmission lines is not perfect, it nonetheless compares very well to other modes of transportation. Since natural gas pipelines are buried and isolated from the public, pipeline accidents involving fatalities and injuries are unusual.

The annual number of fatalities and injuries associated with natural gas transmission lines is typically around 10 to 15, combined. For example, in 2005 there were 3 fatalities and 7 injuries associated with our pipelines and in 2002 -2004, there was 1 fatality per year. Most of these fatalities and injuries are either pipeline company personnel, excavators associated with accidental damage from excavation equipment, or vehicle collisions with pipeline facilities.

There are rare exceptions. The accident that occurred near Carlsbad, New Mexico in 2000 resulted in the deaths of 12 family members who were camping on a remote pipeline right-of-way. That accident was the result of internal corrosion on a section of pipe that could not be inspected by internal inspection devices due to engineering constraints (more on that issue below). This has been the only gas transmission corrosion incident with fatalities since 1985, when PHMSA changed its record keeping system.

The Department of Transportation defines a "reportable incident" as one that results in a fatality, an injury, or property damage exceeding $50,000. Included in the determination of property damage, however, is damage to the pipeline itself and the *monetary value of the natural gas lost*. Without question, the largest single factor in recent numbers has been the value of the natural gas lost. This is due to the fact that natural gas commodity prices have increased, on average, 300 percent since 2002. Minor incidents that, a few years ago, would not have met the threshold for a reportable incident, are now being reported because natural gas commodity prices are so much higher now than five years ago. This fact is skewing the accident data in unintended ways, pointing to the need to change the criteria for reportable incidents so that safety performance results and trends may be accurately identified and evaluated. For example, normalizing the data based on 2002 gas prices would have resulted in 60 fewer onshore incidents being reported for 2005.

Natural gas commodity prices are likely to remain volatile for the foreseeable future, meaning that safety data based on the value of natural gas lost will also be subject to major swings. INGAA suggests that PHMSA or Congress consider a volumetric threshold instead based on 2002 prices. This volumetric approach would provide more consistency in the accident data and therefore more accurately reflect accident trends.

THE PIPELINE SAFETY IMPROVEMENT ACT OF 2002 AND INTEGRITY MANAGEMENT

The most recent reauthorization bill – the Pipeline Safety Improvement Act of 2002 (PSIA) – focused on a variety of issues, including operator qualification programs, public education, and population encroachment on pipeline rights-of-way. But the most significant provision of the bill that will improve long-term pipeline safety dealt with "Integrity Management Programs" (IMPs) for natural gas transmission pipelines.

Section 14 of the PSIA requires operators of natural gas transmission pipelines to: 1) identify all the segments of their pipelines located in "high consequence areas," or areas adjacent to significant population; 2) develop an integrity management program to reduce the risks to the public in these high consequence areas; 3) undertake baseline integrity assessments, or inspections, at all pipeline segments located in high consequence areas, to be completed within 10 years of enactment; 4) develop a process for making repairs to any anomalies found as a result of these inspections; and 5) reassess these segments of pipeline every 7 years thereafter, in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed by one of the following methods: 1) an internal inspection device (or a "smart pig" device); 2) hydrostatic pressure testing (filling the pipe up with water and pressurizing it well above operating pressures to verify a safety margin); 3) direct assessment (digging up and visually inspecting sections of pipe), or 4) "other alternative methods that the Secretary determines would provide an equal or greater level of safety." The pipeline operator is then required to fix all non-innocuous imperfections. For natural gas transmission pipelines, internal inspection devices will be the primary means of integrity assessments. This is due to the fact that the other alternatives listed in the legislation are more difficult to use, and/or require the pipeline to cease or significantly curtail gas delivery operations for periods of time unacceptable long to both ourselves and our customers.

In-line internal inspection "smart pig" devices were actually invented by the natural gas pipeline industry several decades ago, and over the years their capabilities and effectiveness as analytical tools has increased. However, there are some legacy issues our industry must deal with in order to more fully utilize these devices.

First, our pipelines were originally engineered to move natural gas, a compressible substance. This means that older pipelines were often built with tight pipe bends, or non-full pipe diameter valves, continuous sections of pipe with varying diameters, and side lateral piping. In all these circumstances, the movement of natural gas is not impeded because of its relative compressibility. However, introducing a solid object into such pipelines is another matter. These older pipeline systems must be modified to allow the use of internal inspection devices.

The other legacy issue is the modification of pipelines to launch and receive internal inspection devices. Since a pipeline is buried underground for virtually its entire length, the installation of aboveground pig launchers and receivers is usually done at or near other above ground locations such as compressor stations. These stations are typically located along the pipeline at a spacing of 75 to 100 miles apart. Therefore, for every segment, another set of launchers and receivers needs to be installed. Once installed, these launchers and receivers can usually remain in place permanently.

Surveys conducted by our industry about five years ago suggested that almost one-third of transmission pipeline mileage could immediately accommodate smart pigs, another one-quarter could accommodate smart pigs with the addition of permanent or temporary launching and receiving facilities, and the remainder, about 40-45 percent would either require extensive modifications or never be able to accommodate smart pigs due to the physical or operational characteristics of the pipeline. Scheduling these extensive modifications to minimize consumer delivery impacts has been challenging.

The natural gas pipeline industry will use hydrostatic testing and direct assessment for segments of transmission pipeline that cannot be modified to accommodate smart pigs, or in other special circumstances. There are issues worth noting with both hydrostatic testing and direct assessment. In the case of hydrostatic testing, an entire section of pipeline must be taken out of service for an extended period of time, limiting the ability to deliver gas to downstream customers and potentially causing market disruptions as a result. In addition, hydrostatic testing – filling a pipeline up with water at great pressure to see if the pipe fails – is a destructive or "go – no go" testing method that must take into account pipeline characteristics so that it does not exacerbate some conditions while resolving others.

Direct assessment is generally defined as an inspection method whereby statistically chosen sections of pipe are excavated and visually inspected at certain distance intervals along the pipeline right-of-way based on sophisticated above ground electrical survey measurements that predict problem areas. The amount of excavation and subsequent disturbance of landowner's property involved with this technology is significant and does not decrease with subsequent inspections. Disturbing other infrastructures, including roads and other utilities, is also a significant risk and inconvenience for the public.

INTEGRITY MANAGEMENT PROGRESS TO DATE

The integrity management program mandated by the PSIA is performing very well. The program is doing what Congress intended; that is, verifying the safety of gas transmission pipelines located in populated areas and identifying and removing potential problems before they occur. The two years of data is starting to identify a trend that our pipelines are becoming safer.

PHMSA immediately initiated a rulemaking to implement the gas integrity requirements upon enactment of the PSIA in December of 2002. The Administration successfully met the one year deadline set by the law for issuing a final IMP rule. Therefore, 2004 was the first full year of what will end up being a nine-year baseline testing period (the statute mandates that baseline tests on all pipeline segments in high consequence areas must be completed by December of 2012). PHMSA's final rule credits pipeline companies for some integrity assessments completed before the rule took effect, thereby mitigating the effects of the shorter baseline period.

INGAA has surveyed its membership on progress achieved thus far:

1. Total Gas Transmission Mileage in the United States – There are approximately 295,000 miles of gas transmission pipeline in the U.S. INGAA's members own approximately 200,000 miles of this total, with the remainder being owned by *intra*state transmission systems or local distribution companies.
2. Total High Consequence Area (HCA) Mileage – There are approximately 20,000 miles of pipeline in HCAs (i.e., mileage subject to gas integrity rule). This represents about 7 percent of total mileage.
3. HCA Pipeline Miles Inspected to Date –
    - 2004 – 4,043 miles (incorporated some prior inspections before rule took effect).
    - 2005 – 2,739 miles
    - Therefore, 6,686 miles of HCA pipeline inspected to date, or 33 percent of total.

4. Total Pipeline Miles Inspected (including non-HCA pipeline) –
    - 2004 – 30,628 miles (7.57 to 1 over-test ratio)
    - 2005 – 19,670 miles (7.18 to 1 over-test ratio)
    - Therefore, 50,298 total miles, or approximately 17 percent of total transmission pipeline mileage.

The total amount of HCA pipeline mileage inspected to date suggests that the industry is generally on track with respect to meeting the 10-year baseline requirement. With three years of the baseline period completed at the end of 2005, about 30 percent of the HCA mileage had been completed. This translates into 10 percent being completed annually – exactly the volume of work needed in order to meet the baseline requirement.

The 2002 Act also required a prioritization of these HCA assessments, so that the "riskiest" HCA pipeline segments would be scheduled for assessment within five years of enactment. This means that by December of 2007 we must have completed at least half of the total HCA assessments, by mileage, and that work contains the segments with the highest probability of failure. Again, we appear to be on track for meeting this requirement.

The miles actually counted as being assessed in 2004 is higher than what we anticipate the average annual miles will be going forward, because we were able to include some HCA segments that had been inspected in the few years immediately prior to the rule taking effect. As mentioned previously, this helped to jump-start the program and make up for the fact that the final IMP rule did not take effect until December of 2003, thus reducing the *de facto* baseline period to nine years.

The vast majority of the assessments to date have been completed via smart pig devices. As discussed previously, these devices can only operate across entire large segments of pipeline – typically between two compressor stations. A 100 mile segment of pipeline may, for example, only contain 5 miles of HCA, but in order to assess that 5 miles of HCA, the entire 100 mile segment between compressor stations must be assessed. This dynamic is resulting in a large amount of "over-testing" on our systems. While we have completed assessments on 6,686 miles of HCA pipe thus far, the industry has actually inspected almost 50,298 miles of pipe in order to capture the HCA segments. Any problems that are identified as a result of inspections, whether in an HCA or not, are repaired.

As you can see from the data, only about 7 percent of total gas transmission pipeline mileage is located in HCAs. Yet, due to the over-testing situation, we anticipate that about 55 to 60 percent of total transmission mileage will actually be inspected during the baseline period.

Now let us look at what the integrity inspections have found to date. For this data, we focus on information from HCA segments, since these segments are the only ones covered under the integrity management program.

1. Reportable Incidents in HCAs (20,116 miles)
    - 2004 – 9 (2 time-dependent)
    - 2005 – 9 (0 time-dependent)
2. Leaks (too small to be classified as a reportable incident) in HCAs (20,116 miles)
    - 2004 – 117 (29 time-dependent)
    - 2005 – 105 (22 time-dependent)
3. Immediate Repairs in HCAs Found by Inspections (repair within 5 days)
    - 2004 – 106 (3,947 miles inspected)
    - 2005 – 237 (2,739 miles inspected)
4. Scheduled Repairs in HCAs Found by Inspections (repair generally within 1 year)
    - 2004 – 628 (3,947 miles inspected)
    - 2005 – 402 (2,739 miles inspected)

In the data for incidents and leaks, we separate out the number associated with time-dependent defects, since these are the types of defects the reassessment aspects of the integrity management program are really designed to address. What do we mean by time-dependent? By this, we mean problems with the pipeline that develop and grow over time, and should therefore be examined on a periodic time basis. The most prevalent time-dependent defect is corrosion; therefore, the IMP effort is focused most significantly on corrosion identification and mitigation. These same assessments might also be able to identify other pipeline defects such as excavation damage or original construction defects. However, most reportable incidents caused by excavation damage (more than 85 percent) result in an immediate pipeline failure, so periodic assessments are not likely to reduce the number of these types of accidents in any significant way. Original construction defects are usually found and addressed during post-construction inspections; any construction defects found with this new inspection technology would be fixed "for good" so that future assessments looking for these types of anomalies are unnecessary. Periodic assessments on a fixed schedule are therefore most effective for time-dependent defects.

You can see that the number of incidents and leaks associated with time-dependent defects is fairly low. As these defects are found and repaired, we expect these numbers to drop even further, since the gestation period for these defects is significantly longer than the re-inspection interval. Also, data from operators who have completed more than one such periodic assessment over several years strongly suggest a dramatic decrease in the occurrence of time-dependent defects requiring repairs.

As for repairs, we have identified the number of "immediate" and "scheduled" repairs that have been generated by the IMP inspections thus far. These are anomalies in pipelines that have not resulted in a reportable incident or leak, but are repaired as a precautionary measure. "Immediate repairs" and "scheduled repairs" are defined terms under both PHMSA regulations and engineering standards. As the name suggests, immediate repairs require immediate action by the operator, due to the higher probability of a failure in the future. Scheduled repair situations are those that require repair within a longer time period because of their lower probability of failure.

Even though we are very early in the baseline assessment period, the data suggests a very positive conclusion regarding the effectiveness of integrity management programs. "Immediate repairs" in HCA's removed 50 anomalies for every 1000 pipeline miles inspected. The number of "scheduled repairs" removed an additional 60 anomalies per 1000 miles inspected. By completing these immediate and scheduled repairs in a timely fashion, we are reducing the possibility of future incidents or leaks.

Many of the gas pipelines being inspected under this program are 50 to 60 years old. While is it often hard for non-engineers to accept, well-maintained pipelines can operate safety for many decades. Policymakers often compare pipelines to vehicles and ask questions such as: Would you fly in a 50-year-old airplane? The comparison to aircraft or automobiles is an unsound one, though, from an engineering standpoint. In fact, natural gas pipelines are built to be robust, and are not subject to the same operational stresses as vehicles. Much of the above inspection data comes from pipelines that were built in the 1940s and 1950s. And yet, the number of anomalies found on a per-mile basis is low. Once these anomalies are repaired, the "clock can be reset" and these pipelines can operate safely and reliably for many additional decades. One important benefit of the integrity management program is the verification and re-certification of the safety on these older pipeline systems.

ISSUES FOR THE 2006 REAUTHORIZATION

The 2002 Act authorized the federal pipeline safety program at the Department of Transportation through fiscal year 2006. INGAA and its members support completion of the 2006 reauthorization by the beginning of the fiscal year in October. Although the Congressional schedule for the rest of 2006 is short, the current program is working very effectively and therefore needs only modest changes. We therefore see no reason why Congress cannot reach consensus and complete a reauthorization bill this year. INGAA also urges the Congress to pass a five-year reauthorization bill that would take the next reauthorization outside of the time-crunch of a future election year.

INGAA would like the Subcommittee to consider amendments addressing three issues in the pipeline safety law. Each of these would achieve an evolutionary change in the current pipeline safety program: 1) re-consideration of the seven-year reassessment interval, to one based instead upon a more reasoned approach, 2) improvements in state excavation damage prevention programs, and 3) change in the jurisdictional status for direct sales lateral lines.

Seven-Year Reassessment Interval

Under the PSIA, gas transmission pipeline operators have 10 years in which to conduct baseline integrity assessments on all their pipeline segments located in high consequence areas (HCAs). However, operators are also required to begin reassessments of previously inspected pipe seven years after the initial baseline, and every seven years thereafter. PHMSA has interpreted these two requirements to mean that, for those segments baseline-inspected in 2004 and 2005, or if a prior assessment is relied upon, reassessments must be done in years 2011 and 2012, respectively – *even though the baseline inspections are still being conducted*.

If we assume that ten percent of HCA mileage will be inspected under the baseline for each of these three years, as well as the same 10 percent of mileage required for re-inspection in each of the last three years, that translates into our industry conducting inspections on approximately 20 percent of total HCA mileage for each of years 2010, 2011 and 2012. This "overlap" in baseline inspections and re-inspections will cause, we believe, some significant operational challenges as we also work to keep sufficient natural gas flowing to markets.

The seven-year reassessment interval included in the PSIA does not have a basis in either science or engineering. This reassessment interval was included in the 2002 law as a compromise, and with the understanding that Government Accountability Office (GAO) would conduct an analysis of this question prior to the next reauthorization. That GAO study has been underway for some time now, and INGAA and its member companies have provided information to the GAO for its consideration. We hope the GAO will agree that a more technically-based inspection interval alternative is preferable.

What interval does make sense? In 2001, INGAA provided Congress with a proposed industry consensus standard on reassessment intervals that had been developed by the American Society of Mechanical Engineers (ASME). The ASME standard used several criteria to determine a reassessment interval for a particular segment of pipe, such as the operating pressure of a pipe relative to its strength and the type of inspection technique used. This standard relied upon authoritative technical analyses and a "decision matrix" based on more than 50 years of operational and performance data about gas pipelines.

The ASME standard proposed, for most natural gas transmission pipelines (operating at high pressures), a conservative ten-year reassessment interval. This is not a radical departure from the current seven-year interval in the statute. The standard suggested longer inspection intervals for lower pressure lines, but these are a small number of pipelines, and at any rate, are less risky due to their lower operating pressures.

Why are we so concerned about the seven-year reassessment interval? First, there is the question of the "overlap" in years 2010 through 2012. The ability to meet the required volume of inspections is daunting given the limited number of inspection contractors and equipment available. In addition, a heavy amount of inspection activity would be difficult to accommodate without impacting gas system deliverability.

Second, there is the question of whether inspections that are mandated too frequently divert resources from other, more effective safety efforts. The Integrity Management Program asks us to identify and mitigate risks to the public associated with the operation of our pipelines. Inspections are one way to achieve that end – but they are not the only way. The current integrity assessment program focuses primarily on one class of causes of pipeline accidents – corrosion. There are, however, a variety of other risks as well. A credible and effective integrity management program prioritizes risks and develops different strategies for addressing those risks. There may, in fact, be instances where we would want to inspect some pipeline segments *more frequently than seven years* – in highly corrosive environments, for example. A program that mandates system-wide inspections too frequently will severely impact an operator's ability to perform even more frequent inspections at the very few locations that may warrant shorter timeframes.

Damage Prevention

In 1998, the TEA21 highway legislation included a relatively modest program called the "One-Call Notification Act." The goal of this legislation was to improve the quality and effectiveness of state one-call (or "call-before-you-dig") damage prevention programs. By developing some federal minimum standards, and then giving grants to those states that adopted the minimum standards, this Act helped to improve damage prevention efforts all across the nation. And it did so without mandating that states adopt the federal minimum standards.

Over the last eight years, there has been a great deal of improvement in damage prevention. INGAA believes that the time has come to take these efforts to the next level. Excavation damage prevention has been, and should remain, a major focus for pipeline safety. On our gas transmission pipelines, accidental damage from excavation equipment is the leading cause of fatalities and injuries. The majority of incidents that have raised public and Congressional concern have been due to excavation damage. These accidents are the most preventable of all, and better communication between pipeline companies and excavators is the key. Despite all the progress that has been made since 1998, we still have some excavators that do not call before they dig.

One state, in particular, has developed an outstanding damage prevention program based on improved communication, information management and performance monitoring. That state is Virginia. Not only does Virginia require broad participation by all utilities and excavators, but also it has effective public education programs and effective enforcement of the rules. We believe that enforcement is the most important element to improving state programs beyond the progress already made, and we believe Virginia offers a model for other states to adopt. Statistics demonstrate the success of the Virginia program – the state has experienced a 50 percent decrease in the excavation damage since implementing its program.

For 2006, we ask the Congress to once again emphasize the importance of excavation damage prevention by including a new program of incentives for state action. A modest amount a grant funds could go a long way in reducing accidents. INGAA would like to work with the American Gas Association and the Common Ground Alliance in proposing some legislative language on this issue in the next few weeks.

Safety Regulation of Direct Sales Laterals

One of the goals of the original Pipeline Safety Act enacted in 1968 was to establish a clear line of demarcation between federal and state authority to enforce pipeline safety regulations. Prior to 1968, many states had established their own safety requirements for interstate natural gas pipelines, and there was no particular consistency in such regulations across the states. This created compliance problems for interstate pipeline operators whose facilities crossed multiple states. The Pipeline Safety Act resolved this conflict by investing the U.S. Department of Transportation with exclusive jurisdiction over interstate pipeline safety, while delegating to the states authority to regulate intrastate pipeline systems (generally, pipelines whose facilities are wholly within a single state).

The statutory definition of an "interstate gas pipeline facility" subject to federal regulation was clarified further when the Congress reauthorized the Pipeline Safety Act in 1976 (P.L. 94-477). As part of this clarification, the Congress stated that "direct sales" lateral pipelines were not subject to federal jurisdiction. Direct sales laterals are typically smaller-diameter pipelines that connect a large-diameter interstate transmission pipeline to a single, large end-use customer, such as a power plant or a factory. Such direct sales laterals often are owned and maintained by the interstate transmission pipeline operator to which they are connected.

This clarification was made necessary by a 1972 U.S. Supreme Court decision (*Federal Power Commission v. Louisiana Power and Light, 406 U.S. 621*) in which the Court ruled that for purposes of economic regulation (*i.e.*, rate regulation) direct sales laterals were subject to preemptive federal jurisdiction. This ruling created uncertainty regarding the authority to regulate the safety of direct sales laterals, because when the Pipeline Safety Act was enacted in 1968 it was assumed by the Congress that such pipelines would be subject to both economic and safety regulation at the state level.

While this exemption from federal jurisdiction may have made sense 30 years ago, it now is an anachronism. As mentioned, many of these direct sales laterals are owned and operated by interstate pipelines. The natural gas transported in such lines travels in interstate commerce, and the lateral lines are extensions of the interstate pipelines to which they are interconnected. Courts have subsequently affirmed that direct sales laterals are FERC-jurisdictional with respect to economic regulation (see *Oklahoma Natural Gas Co. v. FERC,* 28 F.3d 1281 (1994)), and that states are therefore preempted.

In addition, interstate natural gas pipelines are now subject to the PHMSA's Gas Integrity Management Program, and are required to undergo a specific regimen of Congressionally mandated inspections and safety verification. State-regulated pipelines are not covered under the federal program. Instead, states are allowed to create their own safety programs, which may have different processes/procedures covered than the federal integrity management program. Given the comprehensive federal program, there is no particular reason for small segments of the interstate pipeline system to be subject to differing and potentially inconsistent regulation at the state level. The inefficiency of this approach is further compounded by the fact that an interstate pipeline operator with direct sales laterals in multiple states likely will be subject to inconsistent regulation across the states. It is therefore understandable that interstate pipelines wish to have their direct sales laterals subject to the same federal integrity management requirements as mainline facilities. This would ensure a consistent and rational approach to integrity management system-wide, in contrast to being compelled to exclude parts of the pipeline network on the basis of an outdated set of definitions.

INGAA supports amending the definitions of “interstate gas pipeline facilities” and “intrastate gas pipeline facilities” in the Pipeline Safety Act in order to eliminate the jurisdictional distinction between direct sales laterals and other segments of an operator’s interstate natural gas pipeline system. This would make such segments of pipeline subject to federal safety regulation consistent with the approach taken for the economic regulation of such pipeline facilities.

Direct sales laterals that are not owned by an interstate pipeline could continue to be regulated by states. This amendment also would have the benefit of permitting the states to concentrate their resources on developing and enforcing integrity management programs for their natural gas distribution lines.

CONCLUSION

Mr. Chairman, thank you once again for inviting me to participate in today’s hearing. INGAA has made the reauthorization of the Pipeline Safety Act a top legislative priority for 2006, and we want to work with you and the Subcommittee to move a bill forward as soon as possible. Please let us know if you have any additional questions, or need additional information.

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Summary of Testimony

INGAA appreciates the opportunity to testify on reauthorization of the Pipeline Safety Act. We want to provide the Subcommittee with some background on the natural gas pipeline industry, and discuss the progress being made with the Integrity Management Program that was a part of the 2002 reauthorization. In general, INGAA believes the Integrity Management Program is working well in meeting the intent of Congress to reduce risks to the public. Our recommendations for legislation to reauthorize the Act in 2006 include:

- Five-year reauthorization
- Re-examination of the seven-year reassessment interval that was part of the gas integrity management requirement in the 2002 legislation. We recommend a reassessment interval based on scientific and/or engineering criteria.
- Incentives to further improve state damage prevention programs nationwide.
- Change the definition in the Pipeline Safety Act of "direct sales lateral" pipelines to make those owned by interstate pipelines jurisdiction to federal, rather than state, oversight.